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FUNDAMENTALS OF CRUDE OIL AND NATURAL GAS PROCESSING

The Term project methodical guide
"Sizing gathering and processing system"

Kharkiv – 2016

УДК 622.323
ББК 32.514
Т 38

This book is recommended to publish by the scientific society of the department “Organic substances technology” in National Technical University “Kharkiv Polytechnic Institute” (commission report № 5 from 22.01.2016)

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T 38 Sizing gathering and processing system. The Term project methodical guide / V. Toporov, M. Bratakh, V. Romanova. – Kh., 2016. – 48 p.

This training manual includes term project methodical guide on the course “Fundamentals of crude oil and natural gas processing” in English.

The main purpose of the training manual is to provide students the theoretical and methodological assistance at performance the term project on the course “Fundamentals of crude oil and natural gas processing”. The manual contains the initial data and reference material needed to perform the calculations.

The manual is intended for the students of speciality 6.050304 “Oil and gas production” in English.

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INTRODUCTION

Natural gas produced by gas well is called “raw”. It is fed through the small diameter pipeline (often called flow-line) to gas oil separation plant (GOSP). The composition of raw natural gas consist of a full range of hydrocarbons from gas (methane, ethane) liquefied petroleum gas LPG (butane, propane, etc.), natural gas liquid NGL (medium density hydrocarbons – pentane, hexane) to crude oil. A variety of undesirable components, such as water, carbon dioxide, salts, sulfur and sand present in raw natural gas flow. The purpose of the GOSP is to process the well flow into clean, marketable products: oil, natural gas or condensate.

To perform the term project the next tasks must be fulfill by student:

1. Calculation of the basic technological parameters of gas well stream.
2. Design principles and sizing of gas flow-line, which would provide transport of raw natural gas from wellhead to the GOSP.
3. Basic technological parameters calculation and design principles of the header (chock center) for gathering gas stream from several wells in technological collector at the entrance to GOSP.
4. Select a gas separator and sizing of the two-phase separator.
5. Separator pressure losses calculation.
6. Accuracy analysis.

Performing the project should be started with the selection of data for calculations. Options jobs for group **“B”** are given in Table 1B and for group **“G”** are given in Table 1G.

Data in columns of the Table 1B and Table 1G “Gas flowlines length” should be filled using a map, which shows the location of the GOSP and three wells (Figure 1). Lengths of flowlines L1, L2, L3 are determined by measuring the distance on the map taking into account the scale. Map with location of wells should be provided by the teacher.

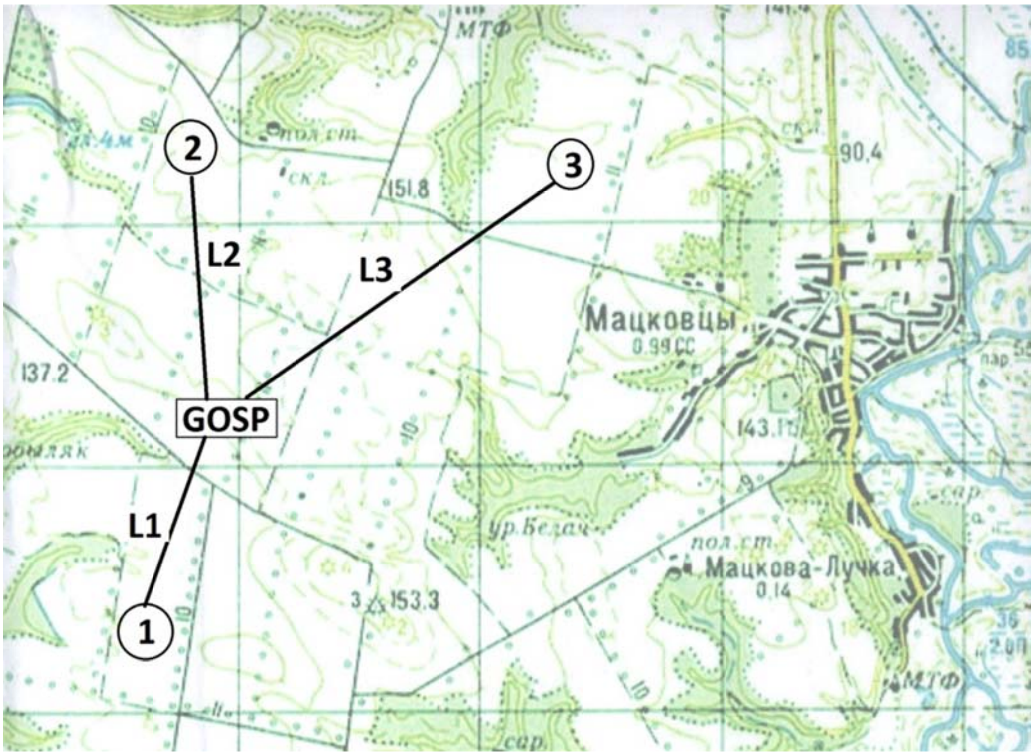


Figure 1 – Map with location of wells

Table 1B – Job options for group “B”

№№	The wellhead pressure			Initial temperature		Static pressure (value must be added to the wellhead pressure), ΔP_{ST} bar	Gas flowlines length			Well flow rates, TCMD			Water content of raw natural gas Δe_0, g/m^3
	P_{W1}, bar	P_{W2}, bar	P_{W3}, bar	Gas t, ^{0}C	Water dew point, ^{0}C		L_1, km	L_2, km	L_3, km	Q_1	Q_2	Q_3	
1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
B1	89	100	79	12	8	+52				1500	1690	1256	357
B2	56	60	35	-1	0	+36				1090	920	780	200
B3	45	41	40	-5	12	+16				1300	1800	1245	643
B4	69	59	55	-10	2	+36				2040	1500	800	789
B5	70	64	63	-8	-1	+32				1300	1200	1000	560
B6	45	24	33	-12	-4	+26				400	420	1000	124
B7	36	35	31	5	-2	+22				894	752	652	76
B8	63	60	56	-2	2	+41				625	459	874	104
B9	136	125	120	-1	12	+59				125	250	375	725

1	2	3	4	5	6	7	8	9	10	11	12	13	14
B10	125	123	119	-6	12	+63				265	298	456	32
B11	88	96	100	10	-3	+32				250	410	690	389
B12	91	110	115	-1	0	+26				290	580	562	625
B13	104	120	102	-5	12	+36				485	405	656	643
B14	55	39	42	-10	2	+30				970	1050	1010	789
B15	27	30	35	-8	-1	+15				1805	1950	790	560
B16	42	39	44	-12	-4	+12				1650	810	1250	124
B17	72	62	68	10	-2	+19				1245	1120	990	76
B18	37	30	34	-2	2	+48				875	745	632	104
B19	115	112	124	-1	12	+52				415	390	280	725
B20	95	87	100	-6	12	+36				840	990	1320	32
B21	89	84	93	-5	12	+16				400	420	1000	560
B22	56	55	66	-8	-1	+32				894	752	652	124
B23	45	50	61	-12	-4	+26				625	459	874	76
B24	69	75	59	5	-2	+22				125	250	375	104
B25	70	83	80	-2	2	+41				265	298	456	725
B26	45	56	49	-1	12	+59				250	410	690	32
B27	36	40	35	-6	12	+63				290	580	562	389
B28	63	70	60	10	-3	+32				485	405	656	625
B29	36	39	45	-1	0	+26				970	1050	1010	643
B30	25	30	33	-5	12	+36				415	390	280	789

Table 1G – Job options for group “G”

№№	The wellhead pressure,			Initial temperature		Static pressure (value must be added to the wellhead pressure), ΔP_{ST} bar	Gas flowlines length			Well flowrates, TCMD			Water content of raw natural gas Δe_0, g/m^3
	P_{W1}, bar	P_{W2}, bar	P_{W3}, bar	Gas t, ^{0}C	Water dew point, ^{0}C		L_1, km	L_2, km	L_3, km	Q_1	Q_2	Q_3	
1	2	3	4	5	6	7	8	9	10	11	12	13	14
G1	88	84	70	3	15	+50				269	315	425	560
G2	91	96	78	6	10	+45				313	452	359	214
G3	105	110	100	-4	16	+26				514	615	725	389
G4	72	75	68	1	2	+30				970	1020	1010	689
G5	88	84	70	3	15	+50				269	315	425	560
G6	91	96	78	6	10	+45				313	452	359	214
G7	105	110	100	-4	16	+26				514	615	725	389
G8	136	125	116	8	18	+36				387	425	587	625

1	2	3	4	5	6	7	8	9	10	11	12	13	14
G9	56	48	43	16	10	+30				1230	1215	1690	231
G10	39	38	36	15	8	+15				1680	1200	800	456
G11	20	29	21	14	12	+12				2008	2080	2088	489
G12	28	23	19	16	11	+19				2480	3420	1569	650
G13	160	150	120	2	4	+48				1080	1020	1200	139
G14	89	100	79	12	8	+52				1500	1690	1256	357
G15	56	60	35	-1	0	+36				1090	920	780	200
G16	45	41	40	-5	12	+16				1300	1800	1245	643
G17	69	59	55	-10	2	+36				2040	1500	800	789
G18	70	64	63	-8	-1	+32				1300	1200	1000	560
G19	45	24	33	-12	-4	+26				400	420	1000	124
G20	36	35	31	5	-2	+22				894	752	652	76
G21	63	60	56	-2	2	+41				625	459	874	104
G22	136	125	120	-1	12	+59				125	250	375	725
G23	125	123	119	-6	12	+63				265	298	456	32
G24	88	96	100	10	-3	+32				250	410	690	389
G25	91	110	115	-1	0	+26				290	580	562	625
G26	104	120	102	-5	12	+36				485	405	656	643
G27	55	39	42	-10	2	+30				970	1050	1010	789
G28	27	30	35	-8	-1	+15				1805	1950	790	560
G29	42	39	44	-12	-4	+12				1650	810	1250	124
G30	72	62	68	10	-2	+19				1245	1120	990	76

Table 2BG – Natural gas composition (gas component concentrations Ni)

Components	**№ of job options**									
	B1	**B2**	**B3**	**B4**	**B5**	**B6**	**B7**	**B8**	**B9**	**B10**
	G1	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**G8**	**G9**	**G10**
CH_4	89,45	87,15	79,25	83,75	69,55	90,15	85,05	72,95	83,45	75,15
C_2H_6	4,78	7,73	10,75	8,74	14,28	5,79	8,58	10,28	4,28	10,28
C_3H_8	2,45	1,75	4,45	5,28	8,75	1,65	2,82	8,75	4,75	6,75
i-C_4H_{10}	0,14	0,18	2,15	0,39	3,24	0,10	2,16	2,29	3,24	3,44
n-C_4H_{10}	0,23	0,13	1,24	0,28	1,27	0,15	0,20	2,47	1,22	1,25
i-C_5H_{12}	0,06	0,05	0,07	0,09	0,28	0,07	0,09	0,28	0,18	0,48
n-C_5H_{12}	0,04	0,03	0,07	0,04	0,16	0,07	0,08	0,16	0,14	0,12
neo=C_5H_{12}	0,01	0,02	0,01	0,02	0,04	0,02	0,01	0,04	0,04	0,04
C_6H_{14}	0,06	0,05	0,07	0,06	0,05	0,06	0,07	0,05	0,05	0,05
C_7H_{16}	0,02	0,01	0,03	0,01	0,06	0,01	0,02	0,06	0,04	0,06
C_8H_{18}	0,01	0,02	0,01	0,01	0,02	0,01	0,02	0,03	0,02	0,02
C_9H_{20}	0,01	0,01	0,02	0,02	0,01	0,02	0,01	0,01	0,02	0,01
O_2	0,01	0,02	0,01	0,01	0,01	0,02	0,01	0,01	0,02	0,01
N_2	0,48	0,43	0,45	0,46	0,49	0,41	0,42	0,79	0,42	0,45
CO_2	2,25	2,42	1,42	0,84	1,79	1,470	0,46	1,83	2,13	1,89

Components	№ of job options									
	B11	**B12**	**B13**	**B14**	**B15**	**B16**	**B17**	**B18**	**B19**	**B20**
	G11	**G12**	**G13**	**G14**	**G15**	**G16**	**G17**	**G18**	**G19**	**G20**
CH_4	86,22	77,15	76,25	80,75	79,55	92,14	94,15	82,90	93,45	65,18
C_2H_6	7,36	11,73	12,75	8,72	8,28	2,79	1,58	5,28	2,28	15,23
C_3H_8	2,41	6,75	5,45	7,21	4,75	2,61	1,82	3,70	1,75	9,75
$i\text{-}C_4H_{10}$	0,25	1,14	2,15	1,39	3,21	0,10	0,56	2,29	1,24	4,49
$n\text{-}C_4H_{10}$	0,46	0,23	1,24	0,28	1,47	0,15	0,70	2,47	0,22	1,25
$i\text{-}C_5H_{12}$	0,10	0,15	0,07	0,09	0,18	0,07	0,09	0,28	0,18	0,48
$n\text{-}C_5H_{12}$	0,08	0,08	0,07	0,05	0,19	0,07	0,08	0,26	0,14	0,12
$neo{=}C_5H_{12}$	0,01	0,02	0,01	0,02	0,04	0,02	0,01	0,04	0,04	0,04
C_6H_{14}	0,06	0,05	0,07	0,06	0,06	0,06	0,07	0,05	0,05	0,05
C_7H_{16}	0,02	0,01	0,03	0,01	0,05	0,01	0,02	0,03	0,04	0,06
C_8H_{18}	0,01	0,02	0,01	0,01	0,03	0,01	0,02	0,03	0,02	0,02
C_9H_{20}	0,01	0,01	0,02	0,02	0,01	0,02	0,01	0,02	0,02	0,01
O_2	0,01	0,02	0,01	0,01	0,01	0,02	0,01	0,03	0,02	0,01
N_2	0,56	0,43	0,45	0,66	0,38	0,46	0,42	0,79	0,42	0,45
CO_2	2,44	2,21	1,42	0,72	1,79	1,47	0,46	1,83	0,13	2,86
Components	**№ of job options**									
	B21	**B22**	**B23**	**B24**	**B25**	**B26**	**B27**	**B28**	**B29**	**B30**
	G21	**G22**	**G23**	**G24**	**G25**	**G26**	**G27**	**G28**	**G29**	**G30**
CH_4	91,90	83,65	75,18	94,60	87,75	74,85	84,48	86,28	81,65	69,55
C_2H_6	2,28	6,08	12,23	3,36	6,76	12,79	6,02	10,05	7,52	13,70
C_3H_8	1,74	3,75	6,75	0,41	2,75	6,65	6,24	1,47	6,61	9,25
$i\text{-}C_4H_{10}$	1,25	2,24	2,49	0,25	1,12	2,17	1,32	1,12	2,39	3,40
$n\text{-}C_4H_{10}$	0,47	1,22	1,25	0,36	0,23	1,44	0,23	0,18	0,23	1,27
$i\text{-}C_5H_{12}$	0,28	0,18	0,48	0,12	0,25	0,09	0,06	0,06	0,08	0,17
$n\text{-}C_5H_{12}$	0,26	0,14	0,12	0,08	0,07	0,08	0,07	0,06	0,06	0,16
$neo{=}C_5H_{12}$	0,04	0,04	0,04	0,01	0,02	0,02	0,02	0,01	0,02	0,06
C_6H_{14}	0,05	0,05	0,05	0,06	0,05	0,06	0,03	0,04	0,02	0,06
C_7H_{16}	0,03	0,04	0,06	0,02	0,01	0,03	0,01	0,01	0,01	0,05
C_8H_{18}	0,03	0,02	0,02	0,01	0,02	0,02	0,01	0,02	0,01	0,03
C_9H_{20}	0,02	0,02	0,01	0,01	0,01	0,02	0,02	0,02	0,01	0,01
O_2	0,03	0,02	0,01	0,01	0,02	0,01	0,01	0,01	0,01	0,01
N_2	0,79	0,42	0,45	0,26	0,73	0,45	0,62	0,25	0,66	0,38
CO_2	0,83	2,13	0,86	0,44	0,21	1,32	0,86	0,42	0,72	1,90

The calculation №1
PHYSICAL AND CHEMICAL PROPERTIES OF RAW NATURAL GAS

1.1. Molecular weight

The molecular weight of the mixture M_{mix} can be calculated taking into the account the Law of Additive Pressure and Amagat`s Law for mixtures, according which (expression 1.1):

$$M_{mix} = \sum_{i=1}^{n} \frac{M_i \cdot N_i}{100} = \frac{M_1 \cdot N_1 + M_2 \cdot N_2 + ... + M_n \cdot N_n}{100} \qquad (1.1)$$

where N_i – mole fraction of component with index ***i*** (i = 1…n);

M_i – the molecular weight (mass) of the component with index ***i*** (Table 1.1);

n – the total number of component ***i***.

Concentration of the gas components *Ni* are given in the table of natural gas composition (Table 2BG).

1.2. Gas density ρ (kg/m³)

Gas density is defined as mass per unit volume and so can also be derived and calculated from the equation:

$$\rho_0 = M_{\text{mix}} / 22.41 \qquad (1.2)$$

where ρ_0 – density of gas at the normal condition, kg/m^3.

1.3. Natural gas specific gravity

The specific gravity (relative density by air) of a gas is defined as the ratio of the gas density to the density of dry air taken at standard or normal conditions of the temperature and pressure.

At or normal conditions:

$$\Delta_0 = \rho_0 / \rho_{an} = \rho_0 / 1.293. \qquad (1.3)$$

At standard conditions:

$$\Delta_{St} = \rho_{0St}/\rho_{aSt} = \rho_{0St}/1.205. \quad (1.4)$$

ρ_{an}= 1.293 *and* ρ_{aSt}= 1.205 – density of dry air taken at 0°C and 20°C respectively.

1.4. Gas formation volume factor

The formation volume factor for gas is defined as the ratio of volume of 1 mol of gas at a given (operating) pressure and temperature to the volume of gas at standard condition. Using the real gas law and assuming that the Z-factor at standard condition is equal to 1, the equation for formation factor Bg can be written as:

$$B_g = \frac{P_O \cdot T_{o.c.} \cdot Z_{o.c.}}{P_{0.c.} \cdot T_O \cdot Z_O}$$

Recalculation of the gas density at normal conditions into the operating conditions (in situ condition) during gathering, processing and transportation is carried out taking into account the influence of parameters of operating conditions (pressure, temperature, compressibility factor) by the formula:

$$\rho_{O.C.} = \rho_0 / B_g = \rho_0 \frac{P_{O.C.} \cdot T_0 \cdot Z_0}{P_0 \cdot T_{O.C.} \cdot Z_{O.C.}} \quad (1.5)$$

where P_0, T_0, Z_0 – the pressure (0.1013 MPa), temperature (273.15K) and the compressibility factor (Z_0=1.0) corresponding to normal conditions;

$P_{O.C.}$, $T_{O.C.}$, $Z_{O.C.}$ – the pressure (MPa), temperature (K) and compressibility factor corresponding to the operating conditions.

Compressibility factor $Z_{O.C.}$ can be determined by graphs at the Figure 1.1 taking into account critical parameters and reduced pressures $\mathbf{P_{CR}}$ and temperatures $\mathbf{T_{CR}}$ (Table 1.1). In this case the Law of Additive Pressure and Amagat`s Law for real gas mixture must be applied.

The next standard formula can be used for Z-factor estimation if total accuracy is not required:

$$Z_{O.C.} = 1 - 5.5 \cdot 10^6 \cdot P_{O.C.} \cdot \frac{\Delta_0^{1,3}}{T_{O.C.}^{3,3}} \quad (1.6)$$

Table 1.1 – The molecular mass, critical pressures and temperatures of petroleum gases components

№	Components	Molecular mass	P_{CR}, MPa	T_{CR}, K
1	Methane, CH_4	16.04	4.63	190.5
2	Ethane, C_2H_6	30.07	4.87	305.4
3	Propane, C_3H_8	44.10	4.26	369.8
4	isoButane, i-C_4H_{10}	58.12	3.65	408.1
5	normal Butane, n-C_4H_{10}	58.12	3.797	425.2
6	isoPentane, i-C_5H_{12}	72.15	3.381	460.4
7	normal Pentane, n-C_5H_{12}	72.15	3.369	469.6
8	neo-Pentane, neo = C_5H_{12}	72.15	3.199	433.9
9	n-Hexane, C_6H_{14}	86.17	3.031	507.4
10	n-Heptane, C_7H_{16}	100.21	2.736	540.3
11	n-Octane, C_8H_{18}	114.23	2.486	568.2
12	n-Nonane, C_9H_{20}	128.26	2.289	594.6
13	Oxygen, O_2	32.00	5.081	154.8
14	Nitrogen, N_2	28.02	3.399	126.2
15	Carbon dioxide, CO_2	44.01	7.387	304.1
16	Hydrogen sulphide, H_2S	34.08	9.01	373.5

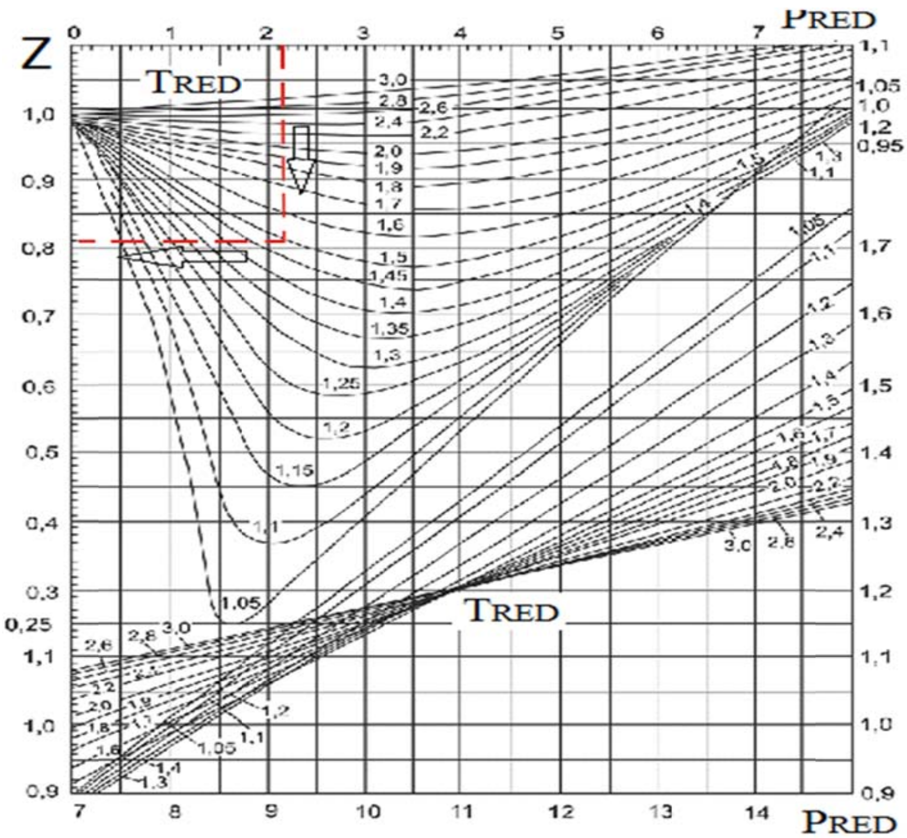


Figure 1.1 – Graphs of dependence Z-factor for hydrocarbons on reduced pressures and temperatures ($T_{RED} = T/T_{CR}$; $P_{RED} = P/P_{CR}$)

1.5. The results of calculation №1

As a result of calculations students must obtain values of the raw natural gas basic properties *for each of the three wells:*

$$M_{mix},\ \rho_0,\ \Delta_0,\ Z_{O.C.},\ \rho_{O.C.}$$

Calculation № 2
HYDRAULIC CALCULATION OF WELL FLOWLINE

Raw natural gas from the well consists of methane as well as many other smaller fractions of heavier hydrocarbons, and various other components. Natural gas has to be separated into marketable fractions and treated to trade specifications and to protect equipment from contaminants.

Many upstream facilities include the gathering system in the processing plant. However, for distributed gas production systems with many (often small) producers, there are little processing at each location and gas production from thousands of wells over an area instead feed into a distributed gathering system. This system in general is composed of [2]:

• ***Flowlines (gathering line):*** A line connecting the wellhead with a field gathering station (FGS), in general equipped with a fixed or mobile type pig launcher.

• ***FGS*** is a system allowing gathering of several flowlines and permits transmission of the combined stream to the central processing facility (CPF) and measures the oil/water/gas ratio. Each FGS is composed of:

- Pig receiver (fixed/mobile);
- Production header where all flowlines are connected;
- Test header where a single flowline is routed for analysis purposes (GOR Gas to oil ratio, water cut);
- Test system (mainly test separator or multiphase flow meter);
- Pig trap launcher.

• ***Trunk line (transmission line*****)** – pipeline connecting the FGS with the CPF. Trunk line is equipped with a pig receiver at the end.

Several schemes can be recommended for field processing and separation of natural gas, but the specific solution is usually a function of the composition of the gas stream, the location of the source, and the markets available for the products obtained. Broadly we can divide all processes that occur with natural gas in upstream and midstream sectors at 3 parts:

- gathering;
- processing;
- transportation.

The task of calculation is to determine the initial diameter of the **well flowline** according to the technical specifications. The size of pipes is normally determined by consideration of its requirement capacity and optimum pressure drop between the wellhead and the header at the Gas Oil Separation Plant – GOSP.

2.1. Flowline initial diameter determination procedure

The inside diameter of the *well flowline* is defined from the fundamental equation of gas pipelines.

$$D_{inner} = 393.287 \cdot \sqrt[5]{\frac{\lambda_{act} \cdot Q^2 \cdot \Delta \cdot T_{av} \cdot L \cdot Z_{av}}{P_{in}^2 - P_{fn}^2}} [mm], \quad (2.1)$$

where λ_{act} – the actual hydraulic resistance coefficient (Oriental value of this coefficient is assumed to be equal to the value of coefficient of hydraulic resistance to friction of the pipe walls λ_{fric}, neglecting influence of local resistance (See table 2.1);

Q – well flow rate, million m^3/day (MCMD);

Δ – specific gas gravity;

T_{av} – average gas temperature, K;

L – distance from the wellhead to the entrance in the GOSP (designing flowline length), km;

$\boldsymbol{Z_{av}}$ – average gas deviation factor or compressibility factor (eq.2.2, 2.3);

$\boldsymbol{P_{in}}$, $\boldsymbol{P_{fn}}$– respectively, the initial (wellhead pressure $\boldsymbol{P_{in}} = \boldsymbol{P_{Wi}}$) and the pressure at the final point of the flowline (header pressure), see **2.1.1**, bar.

Table 2.1 –The value of the coefficient hydraulic resistance to friction corresponding to the productivity at which gas stream in flowline is moving in a quadratic flow regime

The inside diameter of pipeline, D_{inner}, mm	**Productivity (flow rate) of the pipeline Q, corresponding to quadratic flow of a gas stream, TCMD**	**Coefficient of hydraulic resistance to friction λ_{fric}**
25.4	3.7	0.028
40.3	6.5	0.027
50.3	15	0.026
62	28	0.025
76	37.5	0.024
88.6	62	0.023
100.3	70	0.023
125.7	100	0.022
152.3	150	0.021
203.1	260	0.020
	>260	0.015

2.1.1. The sizing the flowline is iteration method of calculation with gradual approach to the required diameter. The following assumption must be taken into account during the first step of iteration (approximation):

- Coefficient of hydraulic resistance to friction should ensure gas transporting process in quadratic gas flow regime, that is, λ is not function of Reynolds number, but depends on equivalent roughness of fixed diameter tubes. Coefficient of hydraulic resistance in the first approximation step is choosen from Table 2.1 according to operating well flow rate (productivity of the flowline);
- The pressure drop in the flowline (the difference between the final pressure P_{fn} and well head pressure P_{in}) must be not higher than 0.3MPa;
- Because of small distance of the flowline natural gas temperature changes not significantly, therefore we can assume that average temperature is equal to the wellhead temperature, i.e. $T_{aver} = T_{O.C.}$

The next sequence of calculation procedure must be completed taking into account the above assumptions

1) the final pressure determination:

$$P_{fn} = P_{in} - 0.3 \text{ [MPa]};$$

2) the average pressure determination:

$$P_{av} = \frac{2}{3} \cdot \left(P_{in} + \frac{P_{fn}^2}{P_{in} + P_{fn}} \right) \tag{2.2}$$

3) the coefficient of compressibility (z-factor) determination:

$$Z_{av} = 1 - 5.5 \cdot 10^6 \cdot P_{av} \cdot \frac{\Delta^{1,3}}{T_{av}^{3,3}} \qquad [P_{av} \text{ in MPa}] \tag{2.3}$$

To ensure the reliability of gas transport from wellhead to the GOSP (e.i. to withstand the maximum pressure in pipeline) at the first step of approximation flowline wall thickness δ estimation procedure is performed. In this case the wall thickness must me quite enough to withstand the maximum load caused by the maximum possible internal pressure of the transporting product – static pressure. Pipe wall thickness is calculated by the formula of SNIP 2.05.06-85 (SNIP – state construction norms and regulations):

$$\delta = \frac{n_p \cdot P_{ST} \cdot D_{inner}}{2R_1} [mm], \tag{2.4}$$

where $\boldsymbol{n_P}$ – coefficient of reliability of the pipeline by main load - internal gas pressure according to SNIP 2.05.06-85, $\boldsymbol{n_P}$ = 1.1;

P_{ST} – maximum internal pressure inside the pipeline equals to well static pressure, $P_{ST} = P_{Wi} + \Delta P_{ST}$, MPa;

D_{inner} – the calculated inside diameter of the pipe, mm;

R_1 – the resistance of the pipe material, MPa.

The resistance of the pipe material is determined by the formula:

$$R_1 = \frac{R_1^N \cdot m}{k_1 \cdot k_N}, \tag{2.5}$$

where R_1^N – normative resistance of the metal equals to tensile strength (ultimate tensile strength) σ_B, which for a certain brand of steel is regarded on the standards or specifications on the pipe (Table 2.2), MPa;

m – coefficient of operating conditions of the pipeline, which is equal to 0.75 for trunk lines and flowlines according to the requirements in SNIP 2.05.06-85;

k_1 – the safety factor for the material of the pipe which is equal 1.55 for well flow lines made of seamless hot formed pipe according to the requirements in SNIP 2.05.06-85;

k_N – safety factor depending on the pipeline purpose taking into the account the pressure in the pipeline and its nominal diameter; for well flow lines made of seamless hot formed pipe at a pressure of $p \le 9.8$ MPa and DN≤500 safety factor is equal to $k_N = 1$, at a pressure of $p > 9.8$ MPa and DN≤500 safety factor is equal to $k_N = 1.05$.

Table 2.2–Tensile strength and yield strength of the seamless hot formed pipes material (GOST 8731-74)

Grade of steel	**Ultimate tensile strength (tensile strength) σ_B MPa (bar), no less than**	**Yield strength σ_T, MPa (bar), no less than**
10	353 (3600)	216 (2200)
20	412 (4200)	245 (2500)
35	510 (5200)	294 (3000)
15XM	431 (4400)	225 (2300)
12XH2	539 (5500)	392 (4000)
Steel SA-516 Grade 70 ASME	485 (4950)	260 (2650)

The nominal thickness of flow line must be chosen from table 2.3 with value next level higher then obtained after calculation by the formula (2.4):

$$\delta_N \ge \delta. \qquad (2.6)$$

Table 2.3 –Nominal wall thickness range of seamless hot formed pipes (GOST 8732-78)

Nominal pipes wall thickness δ_N, mm	**Inside diameter of the pipe, D_{inner}, mm**	**Nominal pipes wall thickness δ_N, mm**	**Inside diameter of the pipe, D_{inner}, mm**
1	**2**	**3**	**4**
3.0	14.0 – 70.0	11.0	32 – 404
3.5	13.0 –95.0	12.0	33 – 402
4.0	12.0 –125.0	14.0	32 – 398
4.5	16.0 –150.0	16.0	34 – 394
5.0	15.0 –149.0	17.0	39 – 291
5.5	14.0 –183.0	18.0	37 – 289
6.0	13.0 –207.0	20.0	49 – 285
7.0	11.0 –159.0	22.0	45 – 281

1	2	3	4
8.0	10.0 –335.0	25.0	58 – 275
9.0	24 – 408	28.0	52 – 269
10.0	22 – 406	30.0	67 – 265

The outside diameter D_{out} of the pipe is given by:

$$D_{out} = D_{inner} + 2\delta_N . \tag{2.7}$$

Nominal value of the outside diameter of flow line D_{out}^N is selected according to the list (Table 2.4) as next larger D_{out}.

Table 2.4 – A nominal number of the most applicable diameters for seamless hot formed pipes (in accordance with GOST 8732-78)

Nominal outside diameter of the pipe, D_{out}^N mm.				
25	28	32	38	42
45	50	54	57	68
70	73	76	83	89
95	102	108	114	121
127	133	140	146	152
159	168	180	194	203
219	245	273	299	325
351	377	402	426	450

If the outer diameter of the pipe exceeds 350 mm, a flowline of two parallel pipes should be designed so that their equivalent diameter is equal to the design value of $\boldsymbol{D_{out}}$. The equivalent diameter of two parallel pipes is determined by the formula:

$$(D_{Eq}^N)^{2.6} = D_1^{2.6} + D_2^{2.6} .$$

The inside diameter of the gas pipeline D_{inner} corresponding to nominal outside diameter and wall thickness of the tube is determined as:

$$D_{inner} = D_{out}^N - 2\delta_N \tag{2.8}$$

Using to table 2.1 the value of coefficient of hydraulic resistance to friction λ_N should be determined next corresponding to $D_{inner.}$ If $\lambda_N \approx \lambda_{act}$ (eq.2.1) the calculation is considered complete, but if $\lambda_N \neq \lambda_{act}$ the calculation should be repeated once again with the new value $\lambda_{act} = \lambda_N$ using the formulas (2.1) – (2.8). This created the second step of approach to the needed diameter.

2.2. Determination of technological parameters of the header at the entrance to GOSP

The individual well streams are brought into the main production facilities over a network of gathering pipelines and manifold systems. The purpose of these pipelines is to allow setup of production "well sets" so that for a given production level, the best reservoir utilization well flow composition (gas, oil, water), etc., can be selected from the available wells (see Figure 2.1).

Natural gas is extracted from the reservoir by using the underground (tubing, casing) and surface (X-mas tree) of production wells equipment (Figure 2.2).

Then gas flows through the flow line to the flow line center (manifolds, chock) of GOSP. Flow line center (it is also called header) is the first unit of GOSP – the place where all flow lines are ended. Flow line center is the block equipped with the lot of valves and lines that help to control the technological regime of all production wells and re-switch the flows (left side of the Figure 2.3).

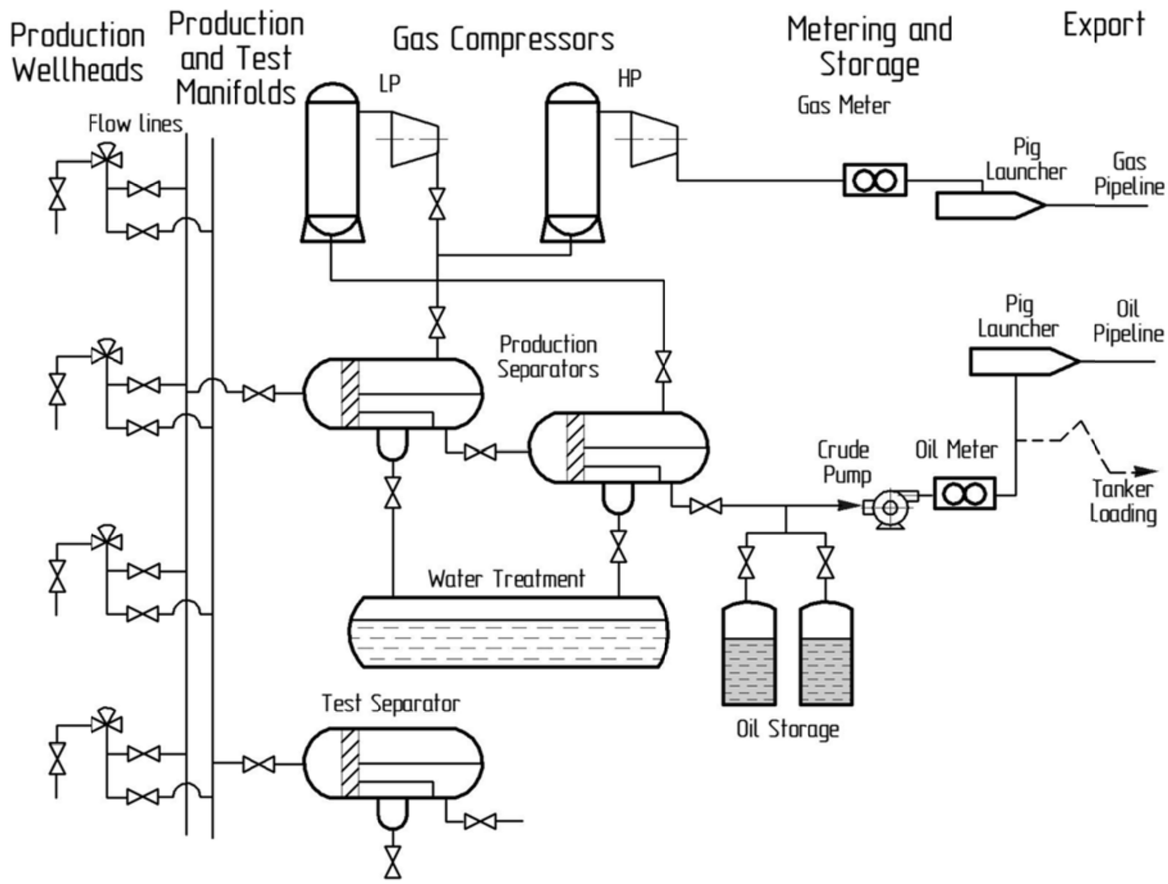


Figure 2.1. – GOSP overview [3]

Figure 2.2 – X-mas tree of gas production well

After gathering at the flow line center natural gas must be processed. All processing equipment locates at GOSP (right side of the Figure 2.3). And first as much as it`s possible operator have to remove the maximum volume liquid from natural gas flow. This liquid is dissolved with natural gas and represented by big drops and vapor of:

- undesirable water from the reservoir;
- really useful natural gas liquid (propane-butane fraction and condensate).

That is why first gas is routed by technological pipelines to the first stage separator, where the largest drops of water and NGL are removed, then gas flows to the second and further stages of separation to remove the vapor of water and NGL from the preliminary treated natural gas.

The system of an entrance of individual wells flowlines (production or test manifold) consists from identical one another lines including a complex of devices for connection of operational wells (control and back-pressure valves, pressure gauges, choke to control the gas flow rate, temperature pocket and etc.)

Operating pressure after mixing gas flow from each manifolds has to ensure normal and uninterrupted operation of all gas wells of a field, so to be less or equal to pressure at the header of any well flow lines connected to main technological collector of the GOSP.

Figure 2.3 – GOSP

Using calculated nominal coefficient of hydraulic resistance λ_N pressure on an entrance to GOSP is determined by a formula:

$$P_{fn} = \sqrt{P_{in}^2 - \frac{9.41 \cdot 10^{12} \cdot Q^2 \cdot \lambda_N \cdot \Delta \cdot T_{av} \cdot z_{av} \cdot L}{D_{inner}^5}} \tag{2.9}$$

Symbols and dimensions of the formula constituents are the same that in a formula (2.1):

To calculate the temperature at the end of the flow line $\boldsymbol{T_{fn}}$ a formula considering the impact Joule-Thomson effect and heat exchanges with environment is recommended:

$$T_{fn} = T_g + \left(T_{in} - T_g\right) \cdot e^{-aL} - Dj \frac{P_{in}^2 - P_{fn}^2}{2 \cdot L \cdot a \cdot P_{av}} (1 - e^{-aL}) \tag{2.10}$$

where:

$$a = \frac{62.6 \cdot k_m \cdot D_{out}}{Q \cdot \Delta \cdot c_p \cdot 10^6}; \tag{2.11}$$

Q – gas flow rate, MCMD;
D_{out} – the outer diameter of the pipeline, mm;
Δ –specific gas gravity;
c_P – specific heat(for approximate calculations $c_P \approx 0.6$kcal /(kg ·°C));
L – design length of the flow line, km;
P_{in} ,P_{fn} – wellhead and header pressure respectively, bar;
P_{av}–average gas pressure in flow line, bar;
T_{in} – the gas temperature at the start of the flow line, K;

T_g – soil, air or water temperature at a depth of laying the pipeline axis, K – table 2.5;

L – length of the flow line, km;

k_m – the coefficient of heat transfer from the gas to the ground, (for approximate calculations k_m = 1.5 kcal / (m^2·h ·K));

e – base of natural logarithms(e =2.718);

Dj – Joule–Thomson effect (for approximate calculations Dj≈0.3K/(bar)).

Table 2.5 – Soil temperature

Ground temperature t_g, °C per month for Kharkiv region												
Month	1	2	3	4	5	6	7	8	9	10	11	12
t_g, °C	2.7	1.9	1.6	4.0	9.6	13.2	15.8	16.7	15.2	11.6	7.7	4.6

2.3. The results of calculation № 2

As the result of calculations you need to obtain next values *for each of the three wells:*

1. Technical characteristics of the well flow line (grade of steel, pipeline wall thickness δ_N, outside and inside diameters of the pipe);
2. Pressure and temperature at the end of gas flow line P_{fn}, T_{fn}.

Calculation № 3
GOSP INLET PARAMETERS CALCULATION
(HEADER CALCULATION)

3.1. GOSP total flow rate

The capacity of technological equipment at GOSP (technological pipelines, header, separators) is defined as overall (maximum) GOSP gas flow rate which is equal to the sum of flow rates of the production wells:

$$Q_{\max} = \sum_{i=1}^{3} Q_i \tag{3.1}$$

where Qi – flow rate of production well with number ***i***, TCMD.

3.2. Header operating pressure

Minimum value from previously calculated pressure at the final point of the each from flowlines must be accepted as header operating pressure (P_W) using next condition:

$$P_W = \min(P_{fn1}, P_{fn2}, P_{fn3}), \tag{3.2}$$

where $P_{fni\_}$ – pressure at the final point of the each from flow lines, MPa.

3.3. Header operating temperature

Operating temperature $\boldsymbol{T_W}$ at the entrance to the GOSP is determined as the average temperature at the final point of the all flowlines using the formula:

$$T_W = \sum_{i=1}^{3} \frac{T_{fni} Q_i}{Q_{\max}}, \tag{3.3}$$

where $\boldsymbol{T_{fni}}$ – temperature at the final point of the flowline with number $\boldsymbol{i}$, K;

Qi – flow rate of well with number i, TCMD.

3.4. NGL and water content estimation

The NGL and water content in a gas stream is defined as the total content of finely dispersed water vapor, finely dispersed NGL vapor and liquid drop with diameter greater than 500 µm:

$$e_0 = W + q' + \Delta e_0, \tag{3.4}$$

where Δe_0 – the content of water drop with diameter greater than 500 µm in a gas stream (the measured content must be taken from Tables 1B, 1G), g/m^3;

q' – NGL vapor content, g/m^3;

W –water vapor content, g/m^3.

NGL vapor content in the gas sample q' is determined based on the percentage of $C_5^{+higher}$ fractions in a gas composition:

$$q' = 10 \sum_{i=5}^{+high} \frac{y_i M_i}{24.04}, \qquad (3.5)$$

where y_i – the content of pentanes and hexanes+higher in the gas composition, % vol (Table 2BG);

M_i – the molar mass of the component, kmol (Table 1.1).

The water vapor content W is determined using table 3.1 with respect to the dew point of natural gas and operating pressure P_W (MPa):

$$W = \frac{A \cdot 1.013}{P_W} + B, \qquad (3.6)$$

where the coefficients A and B are selected from Table 3.1 with respect to the dew point of natural gas (initial data – see Tables 1B, 1G).

Table 3.1 – Values of the coefficients A and B format natural gas

Temperature of water dew point, ^{0}C	**Coefficient *A***	**Coefficient *B***
-20	0.9600	0.01340
-18	1.1440	0.01510
-16	1.350	0.01705
-14	1.590	0.01927
-12	1.868	0.02155
-10	2.188	0.02290
-8	2.550	0.02710
-6	2.990	0.03035
-4	3.480	0.03380
-2	4.030	0.03770
0	4.670	0.04180
+2	5.400	0.04640
+4	6.225	0.05150
+6	7.150	0.05710
+8	8.200	0.06300
+10	9.390	0.06960
+12	10.720	0.07670
+14	12.39	0.08550
+16	13.94	0.09300
+18	15.75	0.1020
+20	17.87	0.1120

3.5. The characteristic of the liquid phase being separated

The main liquid circulating in the separation equipment is accepted according to the:

1) type of liquid phase being separated (type of the liquid phase should be determined by the gas composition, **Table 2BG)**:- for conventional gas field –water;

- for gas-condensate field – NGL;
- for oil and gas field – crude oil.

2) choosing separation stage and type of the dehydration equipment:

Inlet (first stage) separation: water, NGL and oil.

Second stage separation(dehydration of natural gas with absorption):

-DEG;

-Ethanol;

-Methanol.

The density and surface tension of main liquid being separated are shown in Table 3.2.

Table 3.2 – The characteristic of liquid in a separator

№	**Parameter**	**Designa-tion**	**Dimen-sion**	**The liquid types**				
				Water	**Oil**	**NGL**	**DEG**	**Ethanol**
1	Liquid density	ρ_L	kg/m^3	980	800	680	1118.4	789.3
2	Surface tension	σ	10^{-3}N/m	72.86	26.0	15.4	45.0	22.8
3	Product value of 1 x 2	$\sigma\rho_L$	-	71.41	20.8	10.472	50.328	18

3.6. Density of natural gas at the GOSP operating conditions

Gas density ρ_{GW} with respect to the operating pressure P_W and temperature T_W at the GOSP is calculated using gas formation factor and general gas law using the value of gas density at the normal conditions:

$$\rho_{GW} = \rho_0 \frac{P_W \cdot T_0 \cdot Z_0}{P_0 \cdot T_W \cdot Z_W}, \tag{3.7}$$

whereρ_0 – value of the gas density at the normal conditions, kg/m^3;

P_0, T_0, Z_0 – pressure (0.1013 MPa), temperature (273.15K) and the compressibility factor (Z_0 =1.0) corresponding to the normal conditions;

Z_W – compressibility factor at the operating pressure and temperature:

$$Z_W = 1 - 5.5 \cdot 10^6 \cdot P_W \cdot \frac{\Delta_0^{1,3}}{T_W^{3,3}}, \qquad (3.8)$$

where Δ_0 – gas specific gravity (gas relative density by air) at the normal conditions.

3.7. The results of calculation № 3

As a result of calculations you need to obtain the next values:

1.Header operating parameters (flow rate, operating pressure and temperature, compressibility factor and the operating density of natural gas – $Q_{\max}$, P_W, T_W, Z_W, ρ_{GW}).

2. The liquid content of natural gas.

3. Characteristic of main liquid being separated in the inlet and second stage separator.

Calculation № 4
SIZING THE 2-PHASE (GAS-WATER, GAS-CONDENSATE, GAS-OIL) SEPARATOR

In this section, some basic assumptions and fundamentals used in sizing 2-phase separators are presented first. Next, the equations used for designing vertical and horizontal separators are derived. This will imply finding the diameter and length of a separator for given conditions of liquid and gas flow rates, or vice versa.

4.1. Assumptions

1. No oil foaming takes place during the gas–liquid separation (otherwise retention time has to be drastically increased).

2. The cloud point of the liquid and the hydrate point of the gas are below the operating temperature.

3. The smallest separable liquid drops are spherical ones having a diameter of 100 μm.

4.2. Fundamentals

1. The difference in densities between liquid and gas is taken as a basis for sizing the gas capacity of the separator ($\rho_L - \rho_G$).

2. A normal liquid (oil, water, condensate) retention time for gas to separate from oil is between 30 s and 3 min. Under foaming conditions, more time is considered (5–20 min). Retention time is known also as the residence time (=V/Q, where V is the volume of vessel occupied by liquid and Q is the liquid flow rate).

3. In the gravity settling section, liquid drops will settle at a terminal velocity that is reached when the gravity force F_G acting on the liquid drop balances the drag force (F_d) exerted by the surrounding fluid or gas.

4. For vertical separators, liquid droplets separate by settling downward against an up-flowing gas stream; for horizontal ones, liquid droplets assume a trajectory like path while it flows through the vessel (the trajectory of a bullet fired from a gun).

5. For vertical separators, the gas capacity is proportional to the cross-sectional area of the separator, whereas for horizontal separators, gas capacity is proportional to area of disengagement (L·D) (i.e., length x diameter).

6. If separator`s elements separate 2 immiscible liquids than calculation is carried out taking into account properties of liquid, for which value $\sigma\rho_L$ is minimum (table 3.3).

The choice of a separator type is carried out according to table 4.1.

The different types of vertical separator schematic are shown in Figures 4.1-4.2.

Table 4.1 – Operating conditions of separators and separation sections of mass-exchanged devices

Separator`s elements	Operating pressure range, bar	Operating temperature range,^{0}C	Separating phases
Gas separator of a wire-mesh type (Fig. 4.1a, 4.1b)	0.05-80	of -30 to+100	Natural gas, associated gas, NGL, water, corrosion inhibitor, hydrate inhibitor (methanol, DEG, TEG), oil, lubricated oil
Vane type gas separator(Fig. 4.2)	20-140	of -30 to+100	Natural gas, NGL, water, corrosion inhibitor, hydrate inhibitor (methanol, DEG, TEG)

4.3. Sizing 2-phase separator`s elements

4.3.1.Sizing separator cross-sectional area

For the wire mesh vertical separator.

Cross sectional area is equal the area of the wire-mesh section in the direction perpendicular to the gas-liquid flow.

For the vane type vertical separator.

Cross sectional area is equal to the total area of the channels in a section A-A (Figure 4.3a for the 800-mm and 1000-mm separators and Figure 4.3b for the 1200-mm and 1600-mm separators).

1) The settling terminal velocity $\boldsymbol{\omega_{CR}}$(m/s) is determined by the formula:

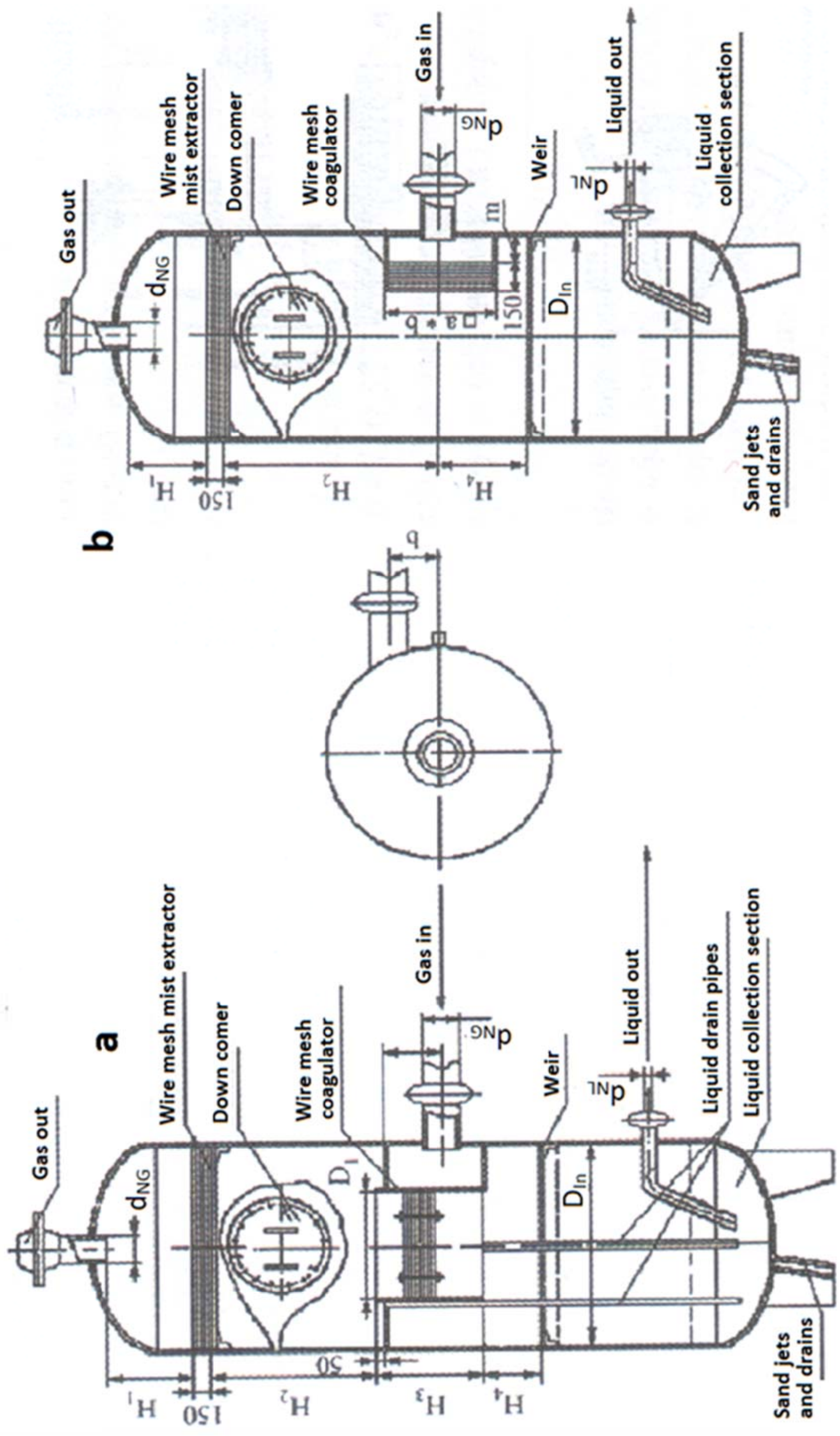
$$\omega_{CR} = C_t \cdot C_e \cdot K \sqrt[4]{\frac{\sigma \cdot g^2 \left(\rho_L - \rho_G\right)}{\rho_G^2}} \tag{4.1}$$

where: C_t – temperature coefficient (*for wire-mesh and vane type separators* $C_t = 1$);

Ce – drag coefficient (depending on account the liquid contentin the gas stream). This coefficient is chosen depending on the value e_0.

If $e_0 \leq 200$ g/m^3 *for mesh and vane type separators the drag coefficient is equal:*

$$C_e = \frac{1.75}{e_0^{0.107}}. \tag{4.2}$$


a
b
Gas out
Wire mesh mist extractor
Down comer
Wire mesh coagulator
Gas in
Weir
Liquid out
Liquid drain pipes
Liquid collection section
Sand jets and drains
d_NG
d_NL
D_In
D_1
H_1
150
H_2
50
H_3
H_4
m
a * b

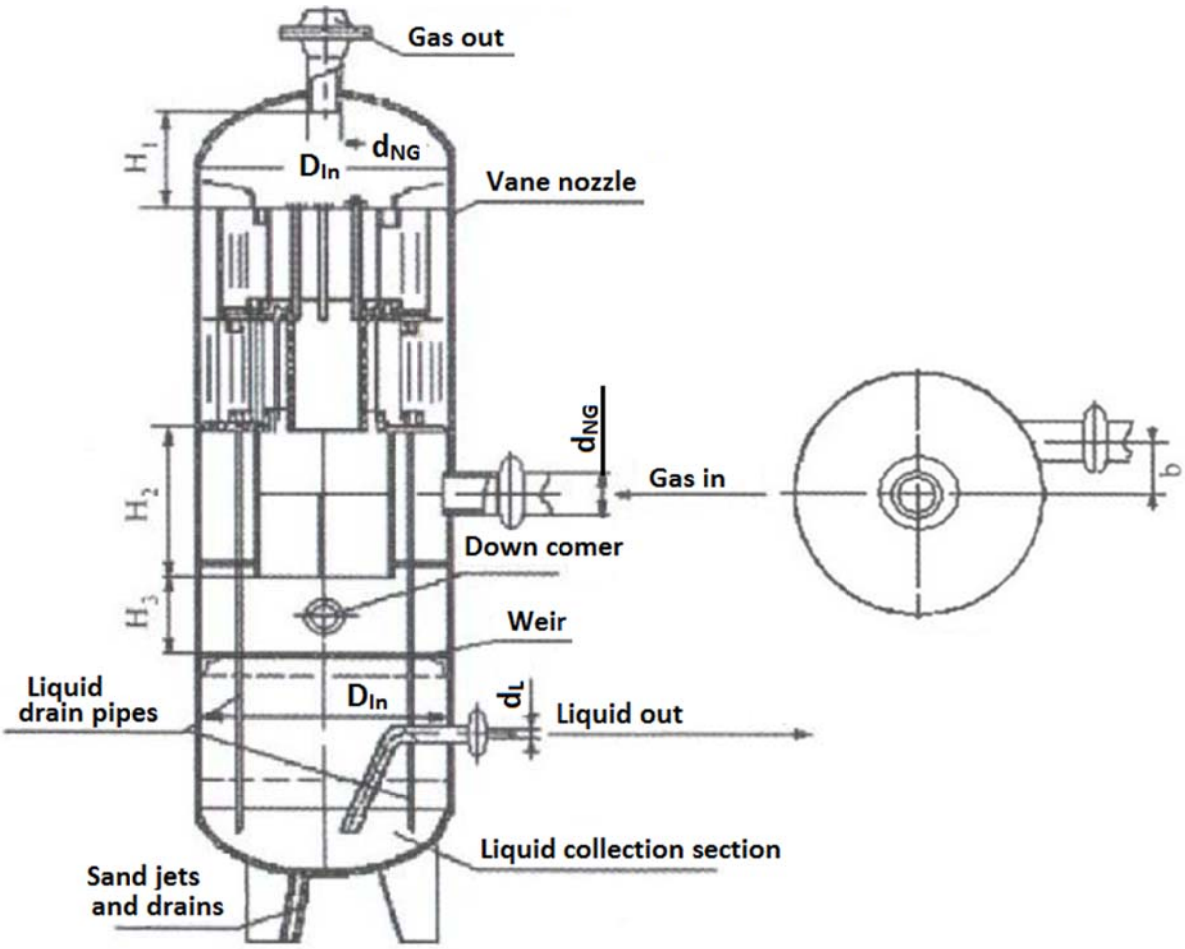


Figure 4.2 – Sketch of vane type separator design with an annular nozzle

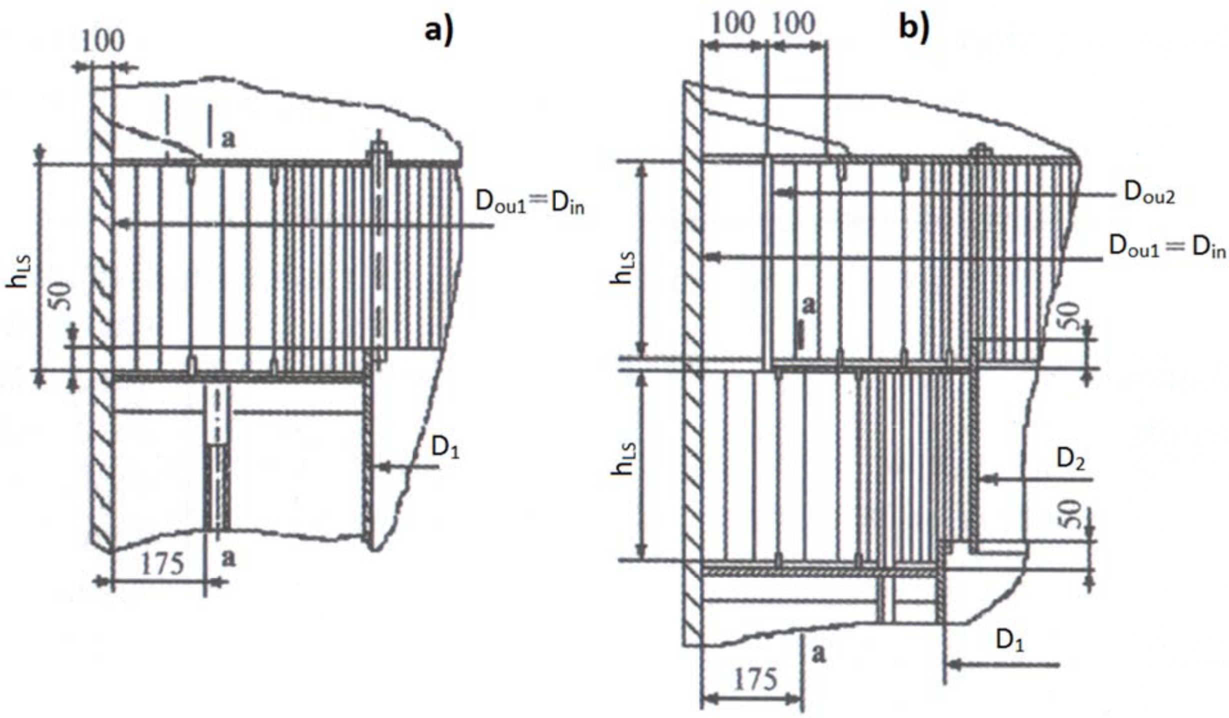


Figure 4.3 – Sketch of the separator vane nozzle

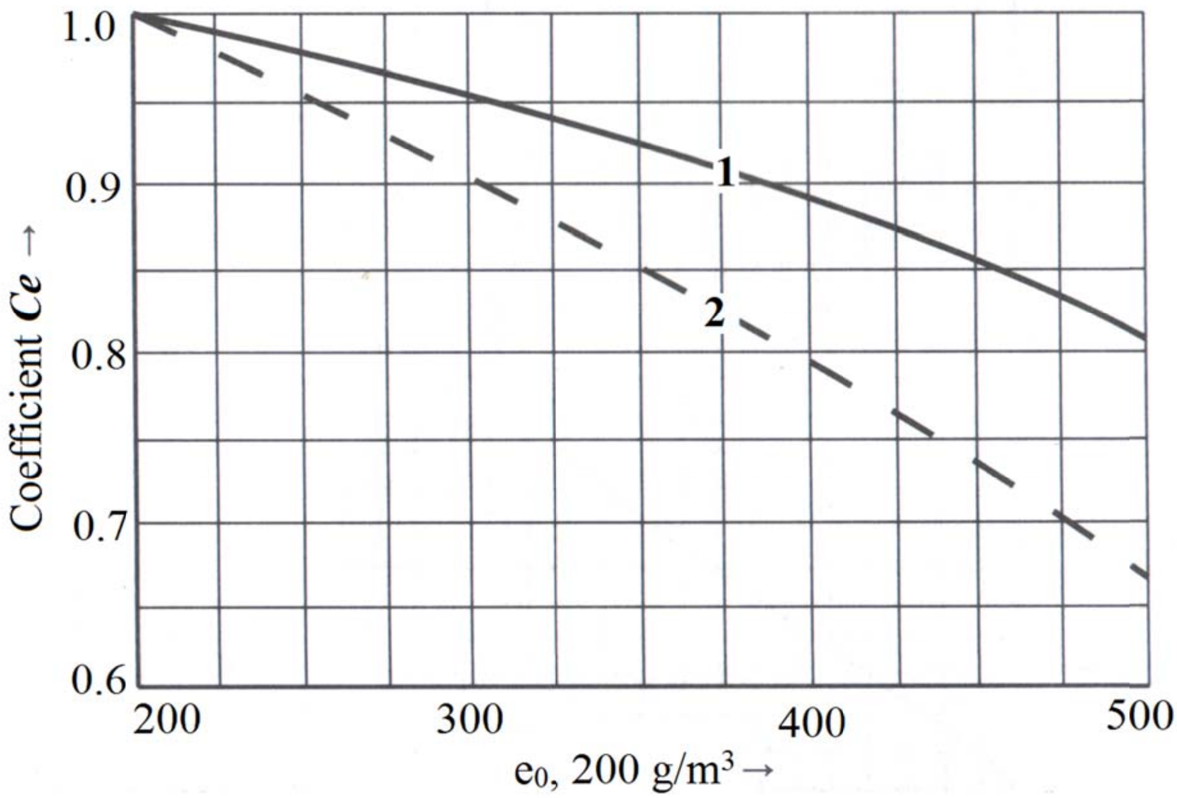


Figure 4.4 – The coefficient *Ce* graphic dependence on the liquid content in the gas stream e_0

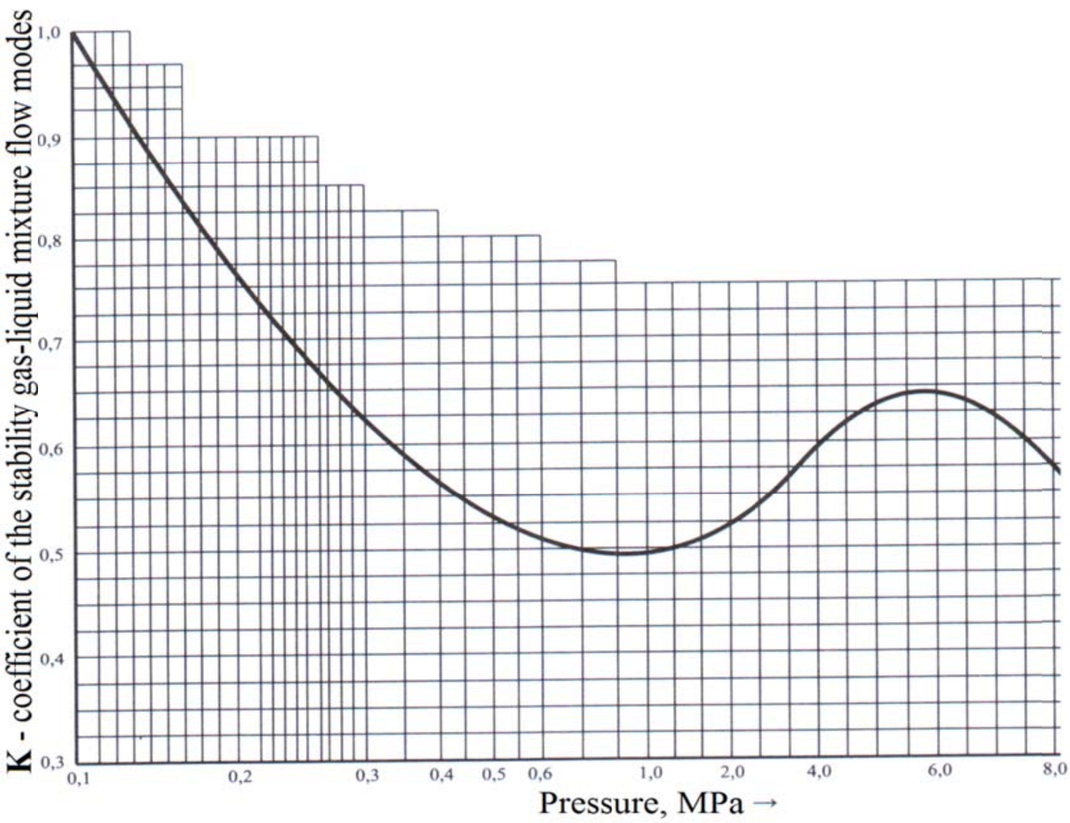


Figure 4.5 – Steady mode coefficient for the wire-mesh type separator

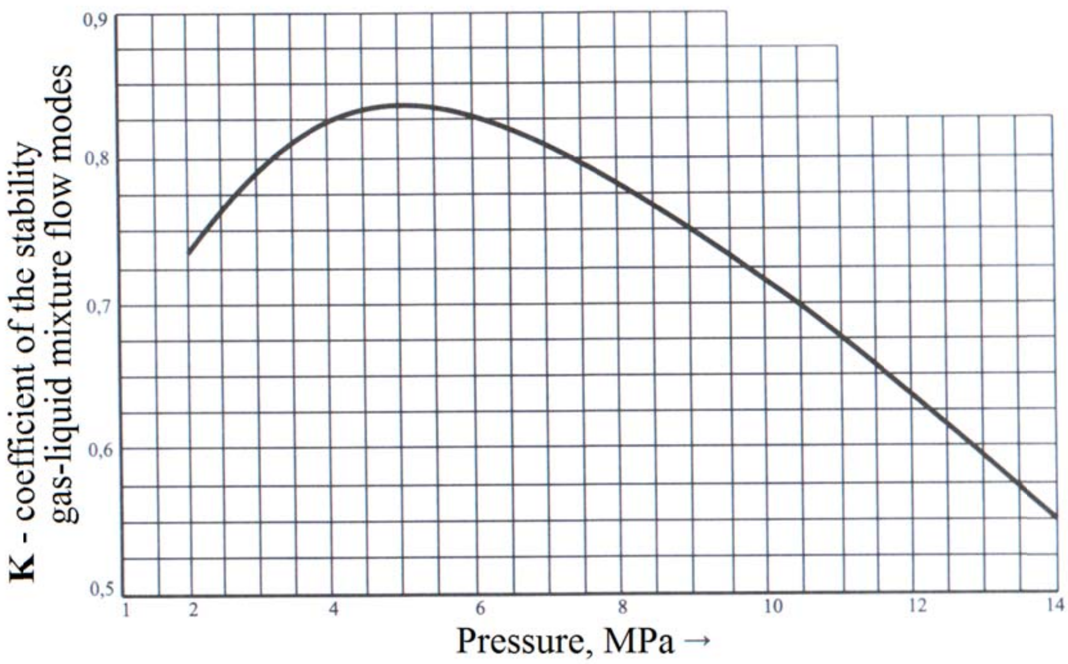


Figure 4.6 –Steady mode coefficient for the vane type separator

If e_0> 200 g/m^3 for all types of nozzles the coefficient is determined within the range between the curves 1 and 2 in Figure 4.4 (*Ce* graphic dependence on the liquid content in the gas stream).

K – steady mode coefficient (shows how even gas-liquid mixture inlet into the separator). The coefficient is taken by Figures 4.5 and 4.6, respectively for the mesh and vane type separator.

2) The volumetric flow rate of gas q_G (m^3/s) for all types of separators is determined by the formula (gas capacity of separator):

$$q_G = \frac{Q_{\max} \cdot P_0 \cdot T_W \cdot Z_W}{86400 \cdot P_W \cdot T_0 \cdot Z_0} \tag{4.3}$$

where $Q_{\max}$ – overall (maximum) GOSP productivity, m^3/day;

3) Cross sectional area of separator is determined by the formula:

$$F = \frac{q_G}{\omega_{CR}} \tag{4.4}$$

4.3.2. Sizing the main separator`s elements

1) Diameter of the wire-mesh nozzle (inner diameter of the gas separator) (m) is given by:

$$D_{In} = 1.13\sqrt{F} \qquad (4.5)$$

Accordingly to GOST 9617-76 "Vessels and apparatus. Series of diameters" obtained internal diameter should be rounded to the next upward from series *179 mm, 245 mm, 374 mm, 550 mm, 800 mm, 900 mm, 1000 mm, 1100 mm, 1200 mm, 1300 mm, 1400 mm, 1500 mm, 1600 mm.*

2). Diameter of the ring inserted vane nozzle in cross section (for the two-stage nozzle – the cross section of the lower stage) is determined from the expression (m):

$$D = \frac{0.37 \cdot F}{n \cdot h_{LS.}} + 0.1(n-1), \qquad (4.6)$$

where n – number of vane nozzle stages, accept n =2;

h_{LS}– height of the vane plate, m, accept h_{LS} =0.42m or h_{LS} =0.52m.

The outer diameter of nozzle (for the two-stage nozzle – on the cross section of the lower stage) is defined by (m):

$$D_{Ou1} = D + 0{,}35. \qquad (4.7)$$

The outer diameter of vane nozzle should be rounded from D_{Ou1} to the next upward D_{Ou2} from series of 800, 900, 1000, 1100, 1200.1300, 1400, 1500, 1600 mm. The outer diameter of lower stage vane is equal to the inner diameter of vane separator:

$$D_{Ou1} = D_{In}. \qquad (4.8)$$

4.4. Sizing the gas and liquid inlet and outlet pipe connections

4.4.1. The definition of the actual diameter gas inlet and outlet pipe connections.

Design inner diameter of gas inlet and outlet pipe connections is given by (m):

$$d_{NG}^{d} = 1.13\sqrt{\frac{q_G}{W_G}}, \qquad (4.9)$$

where W_G – gas velocity in the gas inlet and outlet pipe connection, m/s. The gas velocity in gas inlet and outlet pipe connections, depending on operating pressure is determined by the curve 1 on the graph Figure 4.7.

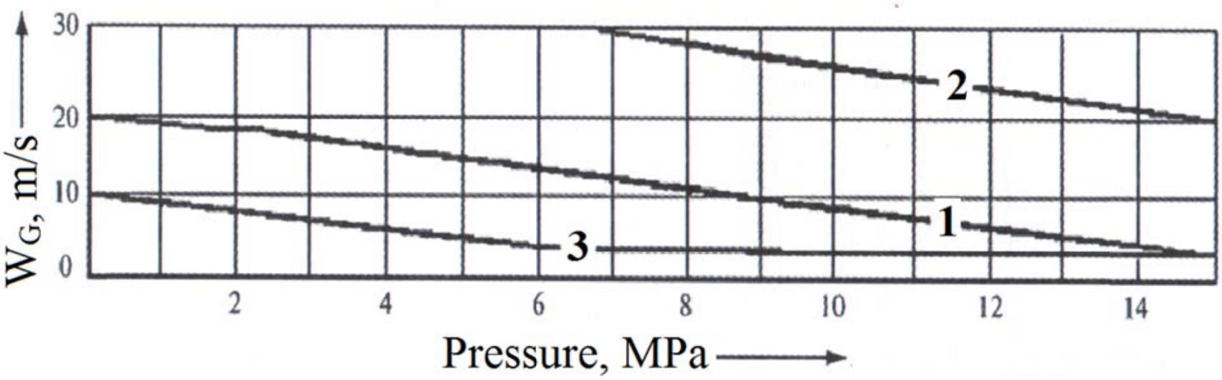


Figure 4.7– Graph of gas movement velocity in the gas inlet and outlet pipe connections on the pressure

The wall thickness of designed gas inlet and outlet pipe connections is defined as for smooth cylindrical pressure vessels(m):

$$\delta_{NG}^{d} = \frac{P_W \cdot d_{NG}^{d}}{2[\sigma]\varphi_{Weld} - P_W} \tag{4.10}$$

where [σ] – is allowable stress for carbon and alloy steels (taking from the table 4.2 according to the requirements of Ukraine GOST 14249-89 *“Vessels and apparatus. Norms and methods of strength calculation”,* USA ASME “*Boiler and Pressure Vessel Code”* and European PED “*Pressure Equipment Directive*”*);*

φ_{Weld} – welded seams strength coefficient.

This coefficient according to the requirements of GOST 14249-89 may be equal from 0.65 to1.0, accept $\varphi_{Weld} = 0.8$.

Table 4.2 –Allowable stress for carbon steels and alloy steels

Design temperature, ^{0}C	**Allowable stress [σ] for carbon steels and alloy steels of the following brands, kgf/cm^2**			
	Cm 3	***Cm 20, Cm 20K***	***Steel SA-516 Grade 70 ASME***	***Steel P295GH EN 10028-2***
20	*1400*	*1470*	*1380*	*1910*
100	*1340*	*1420*	*1380*	*1760*

The actual wall thickness is given by the formula (m):

$$\delta_{NG} = \delta_{NG}^{d} + c \tag{4.11}$$

where ***c*** – the value of additive to the designed wall thickness, taking into account the effect of the manufacturing and aggressive environment. Usually accept ***c*** = 1mm (0.001 m).

Actual wall thickness should be rounded to the nominal value δ_{NG}^{N} according to the Table 2.3.

The outer diameter of gas inlet and outlet pipe connections is determined by the formula (m):

$$D_{NG} = d_{NG}^{d} + 2\delta_{NG}^{N} \tag{4.12}$$

Actual outer diameter should be rounded to the standard value D_{NG}^{N} from adnominal series (Table 2.4). The nominal diameter of gas inlet and outlet pipe connections must be greater than 50 mm.

Actual inner diameter of gas inlet and outlet pipe connections is determined by the formula (m):

$$d_{NG} = D_{NG}^{N} - 2\delta_{NG}^{N} \tag{4.13}$$

4.4.2. The definition of the actual diameter liquid inlet and outlet pipe connections

Actual liquid flow rate (liquid capacity of separator) is determined by the formula (m^3/s) [$\boldsymbol{Q_{max}}$ – m^3/day]:

$$q_L = \frac{e_0 \cdot Q_{\max} \cdot 10^{-6}}{86400}. \tag{4.14}$$

Designed inner diameter of liquid inlet and outlet pipe connections is given by (m):

$$d_L^d = 1.13\sqrt{\frac{q_L}{W_L}}, \tag{4.15}$$

where W_L – liquid velocity in the liquid inlet and outlet pipe connections, accept W_L = 1–2 m/s.

Sizing the actual internal and external diameters of the liquid inlet and outlet pipe connections D_L and d_L is similar to section 4.4.1.

4.4.3. Calculation of the sand jets and drains.

The volume of liquid q_{Ent} entering in the liquid collection section of separator is equal (m^3/s):

- for wire mesh type separators:

$$q_{Ent} = 0.3 \cdot q_L ; \tag{4.16}$$

- for two-stage vane separator:

$$q_{Ent} = q_L . \tag{4.17}$$

Designed internal diameter of the sand jets and drains is given by the formula:

$$d_{Ent}^{d} = 1{,}13 \sqrt{\frac{q_{Ent}}{nW_{Ent}}} , \tag{4.18}$$

where W_{Ent} – speed of liquids drain (from 1 to 2 m/s);

n – number of the pipe connections ($n \geq 2$).

Determining of the actual outer diameter of the sand jets and drains pipes D_{Ent} is similar to section 4.4.1.

4.5. Sizing the liquid collection section for all types gas separators

Sizing the liquid collection section for all types gas separators is meant determining it sactual volume and basic design dimensions. As the volume of *the liquid collection section* its volume to the level controller (weir) without volume of bottom is suggested.

The volume of *the liquid collection section* V_{COL} is determined by the expression (m^3):

$$V_{COL} = 60 \cdot q_L \cdot \tau , \tag{4.19}$$

where $\boldsymbol{\tau}$ – liquid retention time in the **liquid collection section** of the 2-phase separator, min.

For no foaming liquids retention time must be more than 3 minutes.

Cross sectional area of *the liquid collection section* perpendicular to its axis is calculated by the formula:

- for vertical *liquid collection section* (m^2) (Figure 4.8): $F = 0.785 {D_{In}}^2 ;$

- for horizontal and horizontal external *the liquid collection section* (m^2) (Figure 4.9): $F=(0.390\div 0.631){D_{In}}^2$.

Calculated length (height) of *the liquid collection section* (the length of its cylindrical part) is determined by the formula (m):

$$L_{COL}=\frac{V_{COL}}{F}. \tag{4.20}$$

4.6. Sizing the individual separator elements and separator technological sections

4.6.1. Wire mesh type separators

Special mesh-sleeve is used for the manufacture of separation and wire mesh nozzles. These are made of finely woven stainless-steel wire wrapped into a tightly packed cylinder of about 15cm thickness. The liquid droplets that cannot be separated in the gravity settling section of the separator coalesce on the surface of the matted wire, allowing liquid-free gas to exit the separator. As the droplets size grows, they fall down into the liquid phase.

Provided that the gas velocity is reasonably low, wire-mesh extractors are capable of removing about 99% of the 10-μm and larger liquid droplets. It should be noted that this type of nozzle is prone to plugging. Plugging could be due to the deposition of paraffin or the entrainment of large liquid droplets in the gas passing through the mist extractor (this will occur if the separator was not properly designed). In such cases, the vane-type mist extractor, described next, should be used.

Nozzles are manufactured in two versions – a whole (in which the mesh-sleeves rolled into a spiral with a height of 100mm) and sectional (in which the mesh-sleeves are laid as layers (up to 70 layers) alternately along and across, and its height is150 mm).

4.6.1.1. The design parameters of the gas separator with a horizontal coagulator (Figure 4.1a) are determined by the following procedure

– the diameter of the coagulator (nozzle, wire mesh):

$$D_1=\left(0.6\div 0.7\right)D_{In}; \tag{4.21}$$

– the distance from the gas outlet pipe connection to the nozzle:

$$H_1 \geq 0.38\left(D_{In} - d_{NG}\right); \tag{4.22}$$

– the distance from the wire mesh nozzle to the upper edge of the coagulator roll:

$$H_2 \geq 2.85\left(D_{In} - D_1\right); \tag{4.23}$$

– the height of the coagulator roll:

$$H_3 \geq (2 \div 3) \cdot d_{NG}; \tag{4.24}$$

– the distance from the coagulator bottom edge to the weir under the liquid collection section:

$$H_4 \geq 0.25 \cdot D_{In}; \tag{4.25}$$

–radial displacement of the gas inlet pipe connection:

$$b \leq 0.25 \cdot D_{In} \tag{4.26}.$$

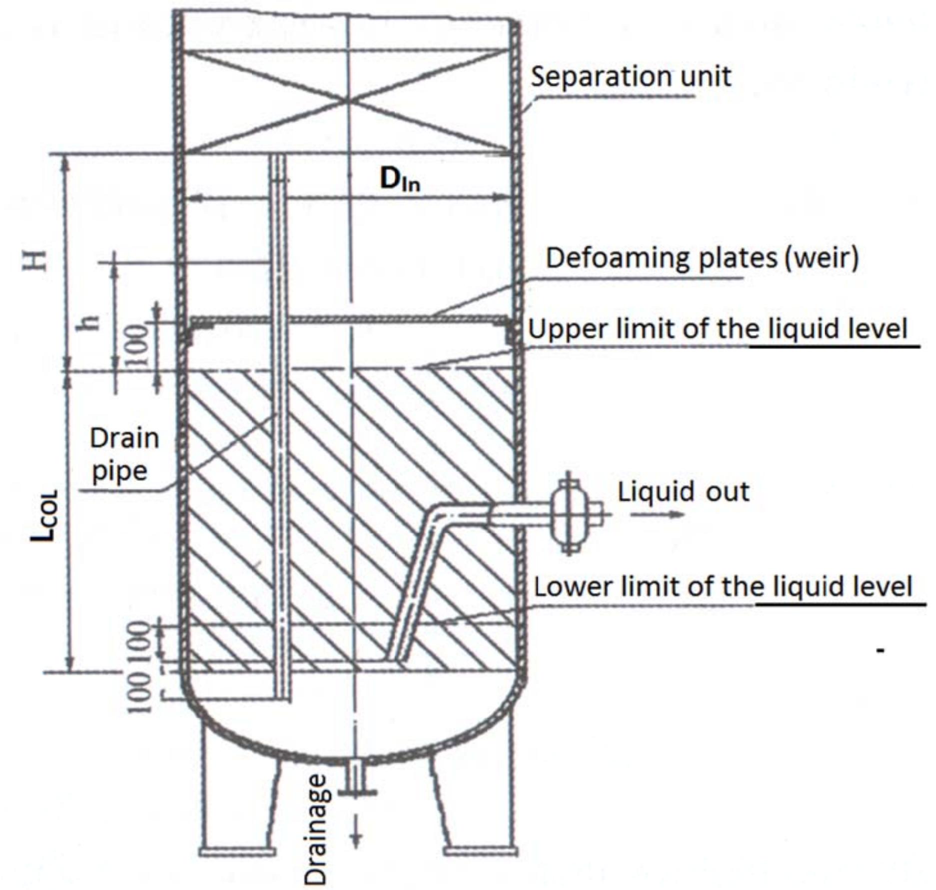


Figure 4.8 – Sketch of a vertical liquid collection section

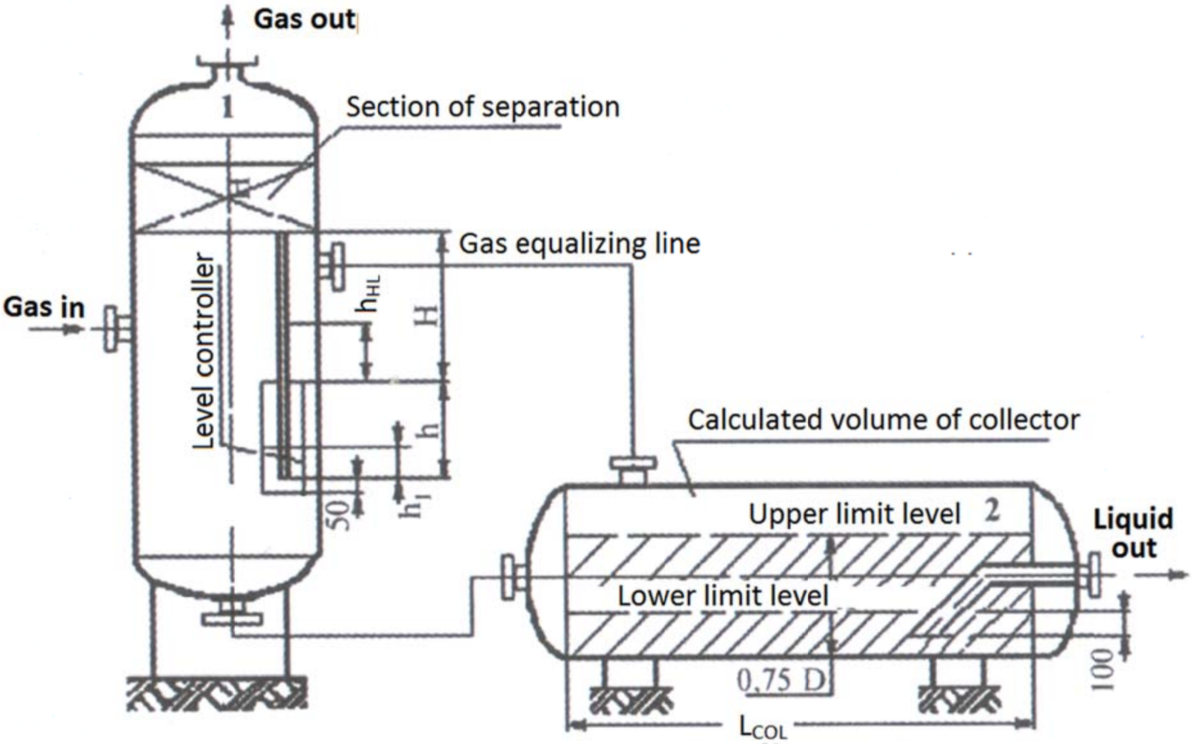


Figure 4.9 – Sketch of the gas mesh separator with a horizontal external liquid receiver layout

4.6.1.2. The design parameters of the 2-phase separator with vertical coagulator (Figure 4.1b) are determined by the following procedure

– the distance from the gas outlet pipe connections to the nozzle:

$$H_1 \geq 0.38\left(D_{In} - d_{NG}\right); \tag{4.27}$$

– the distance from the nozzle to the gas inlet pipe connection axis:

$$H_2 \geq 0.75 \cdot D_{In}; \tag{4.28}$$

– the distance from the gas inlet pipe connection to the weir:

$$H_4 \geq 0.25 \cdot D_{In}; \tag{4.29}$$

– coagulator area of disengagement:

$$a \times b = 4 \cdot d_{NG}; \tag{4.30}$$

– distance from the coagulator to the gas inlet pipe connections:

$$m = \left(0.8 \div 1.0\right) \cdot d_{NG}. \tag{4.31}$$

4.6.2. Vane type 2phase separators

This type of nozzles consists of a series of closely spaced parallel, corrugated plates. As the gas and entrained liquid droplets flowing between the plates change flow direction, due to corrugations, the liquid droplets impinge on the surface of the plates, where they coalesce and fall down into the liquid collection section.

Overall shape of vane plate is shown at the Figure 4.10.

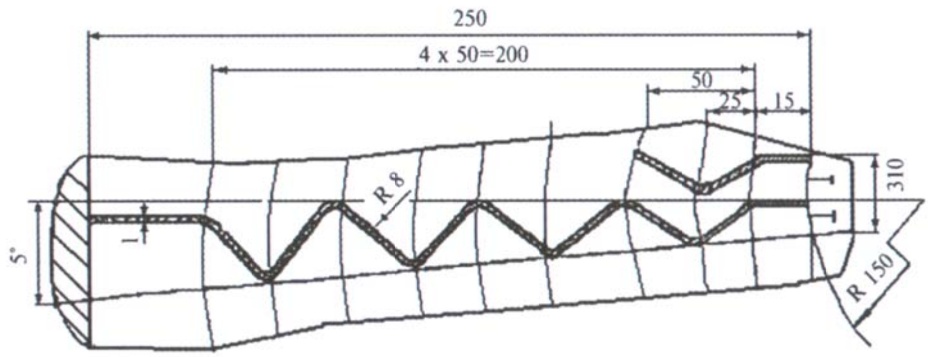


Figure4.10 – Overall shape of vane plate

The design parameters of the vane type gas separator (Figure 4.2) are determined by the following procedure:

– outer diameter of the upper stage nozzle:

$$D_{Ou2} = D_{Ou1} - 0.2; \tag{4.32}$$

– outer diameter of the roll at the input of gas into the nozzle:

$$D_1 = (0.5 \div 0.7) \cdot D_{In}; \tag{4.33}$$

– diameter of roll at the input of gas in the upper stage of the nozzle:

$$D_2 = D_1 \sqrt{\frac{F_{d2}}{F_{d1} + F_{d2}}}, \tag{4.34}$$

where F_{d1}, F_{d2} – the actual design areas of the two-stage vane nozzle cross sections:

$$F_{d1} = \pi \cdot (D_{In} - 0.35) \cdot h_{LS} - f_{LS1}; \tag{4.35}$$

$$F_{d2} = \pi \cdot (D_{In} - 0.55) \cdot h_{LS} - f_{LS2}, \tag{4.36}$$

where h_{LS} – the height of vane plate, m;

f_{LSi} – area of vane plates for stage 1 and stage 2, m^2:

$$f_{LSi} = n_i \cdot h_{LS} \cdot \delta_{LS}, \tag{4.37}$$

where δ_{LS} –thickness of vane plates, m; thickness of vane plate is taken equal 1 mm, δ_{LS} =0.001 m;

n_i – number of vane plates in i-stage:

$$n_i = \frac{\pi(D_{Oui} - 0.5)}{S}; \tag{4.38}$$

S – space between vane plates at the nozzle, m; S = 0.01m;

D_{Oui} – plate outer diameter in i-stage of the nozzle, m.

– distance from the gas outlet pipe connection to the nozzle:

$$H_1 \geq 0.38 \cdot \left(D_{In} - d_{NG}\right); \tag{4.39}$$

– height of the first roll:

$$H_2 \geq \left(2 \div 3\right) \cdot d_{NG}; \tag{4.40}$$

–distance from the roll lower edge at the gas inlet to the weir:

$$H_3 \geq 0.25 \cdot D_{In}; \tag{4.41}$$

–radial displacement of the gas outlet pipe connection

$$b \leq 0.25 \cdot D_{In}. \tag{4.42}$$

4.7. The results of calculation № 4

As a result of calculations you need to obtain the next:

1. Select of a separator type.
2. To calculate parameters of the separator’s element.
3. To calculate dimensions of gas inlet and outlet and the liquid outlet pipe connections.
4. To calculate dimensions of separator liquid collection system.
5. To determine main constructive requirements for individual separator elements and technological sections.

Calculation № 5.
FINAL CALCULATIONS

5.1. Checking the actual gas capacity constraints

5.1.1. For the wire mesh and vane gas separators is necessary to build graphic dependences of the gas capacity (flow rate) on the operating pressure:

$$Q = f(P).$$

To build such graphic dependencies necessary to determine the actual values of productivity (maximum and minimum flow rates Q_{max}^{d}, Q_{min}^{d}) in the required range of operating pressures from P_{max} to P_{min} at the constant design (operating) temperature.

Actual maximum gas capacity of 2-phase separator Q_{max}^{d} is corresponded to the terminal settling gas flow rate and is determined by the formula (m^3/day):

$$Q_{\max}^{d} = \frac{86400 \cdot \omega_{CR} \cdot F \cdot P_W \cdot T_0 \cdot z_0}{P_0 \cdot T_W \cdot z_W}. \qquad (5.1)$$

For the wire mesh and vane separators minimum capacity Q_{min}^{d} is determined at the minimum terminal settling velocity of the gas-liquid flow

$$W_{\min} = 0.5 \cdot \omega_{CR}. \qquad (5.2)$$

Then:

$$Q_{\min}^{d} = 0.5 \cdot Q_{\max}^{d}. \qquad (5.3)$$

5.1.2. The actual cross-section area of separating element with respect to the accepted inner diameter of the wire mesh type separator is determined as:

$$F = 0.785 \cdot D_{In}^{2} - \Delta f, \qquad (5.4)$$

where Δf – area of the supporting elements which is equal to 5% of the wire mesh nozzle total area, m^2.

The actual area of the separating element with respect to the accepted inner diameter of the vane separator is determined as:

– single-stage vane nozzle (eq.4.35):

$$F = \pi \cdot (D_{In} - 0.35) \cdot h_{LS} - f_{LS1}; \qquad (5.5)$$

– two-stage vane nozzle (eq.4.35, 4.36):

$$F = 2\pi \cdot (D_{In} - 0.45) \cdot h_{LS} - f_{LS1} - f_{LS2}, \qquad (5.6)$$

where h_{LS} – actual height of vane plate, m;

f_{LSi} – area of vane plates for stage 1 and stage 2 respectively, m^2:

$$f_{LSi} = n_i \cdot h_{LS} \cdot \delta_{LS}, \qquad (5.7)$$

where $\boldsymbol{\delta_{LS}}$ – thickness of vane plates, m;

$\boldsymbol{n_i}$ – number of the vane plates in i-stage:

$$n_i = \frac{\pi(D_{Oui} - 0.5)}{S}; \qquad (5.8)$$

$\boldsymbol{S}$ – space between vane plate at the nozzle, $\boldsymbol{S}$ = 0,01 m;

D_{Oui} – plates outer diameter in *i*-stage of the vane nozzle, m.

The graph “Capacity over operating pressure” is shown in Figure 5.1. The operating pressure range for separators is defined in table 4.1 (for instance, for wire mesh type separator pressure ranges from 0.05 to80 bar).

Specified operating area will be limited by rectangle with the tops at the crossing of Q_{min} and Q_{max}, P_{min} and P_{max} lines with the minimum and maximum capacity curves.

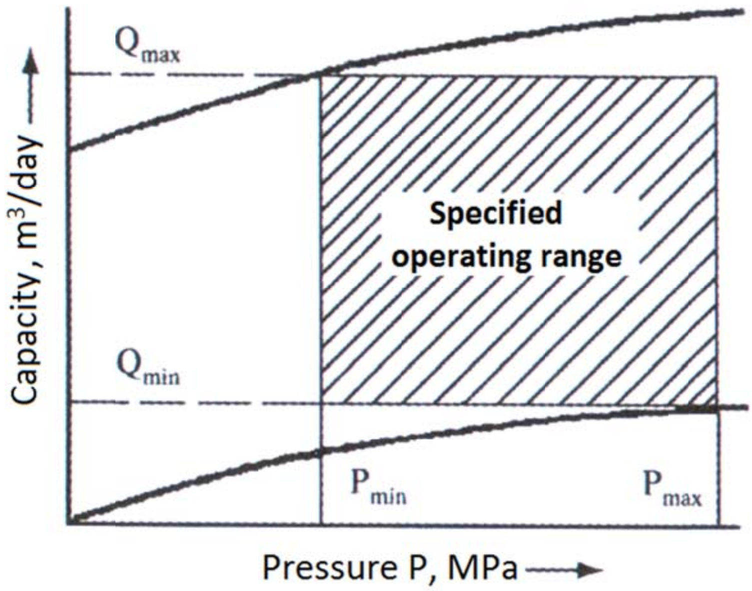


Figure 5.1 – Dependence of the separator capacity on the operating pressure

5.2. Hydraulic calculation of the gas separator

5.2.1. Determination of the pressure loss

Hydraulic loss in separator ΔP must be less than maximum allowable pressure drop that is equal 0.5 bar:

$$\Delta P < [\Delta P], \tag{5.9}$$

where [ΔP] –the allowable pressure drop in the separator equal to 0.5bar.

The value of hydraulic loss for the wire mesh and vane type separators is determined by the formula:

$$\Delta P = \alpha \sum_{i=1}^{n} \Delta P_i, \tag{5.10}$$

where $\boldsymbol{\alpha}$ = 1.1 – coefficient of unaccounted loss;

ΔP_i – separator`s element hydraulic resistance, bar:

$$\Delta P_i = \xi_i \frac{\rho_G \cdot W_i^2}{2 \cdot 10^6} g, \tag{5.11}$$

where W_i – gas velocity in the considering element, m/s:

$$W_i = \frac{q_G}{F_i}, \tag{5.12}$$

where $\boldsymbol{q_G}$ – is volumetric flow rate of gas (m^3/s) determined by the formula (4.3) section 4.3.1.

The values of hydraulic resistance coefficients for the different separator`s element sand separator element areas $\boldsymbol{F_i}$ formulas are presented in Table 5.1.

Table 5.1–The hydraulic resistance coefficients of separator elements

Separator element	**Hydraulic resistance coefficient**	**Element area, m^2**
Gas input	1.0	$F_{NG} = 0.785 d_{NG}^2$
Horizontal coagulator	See Figure 5.2	$F_C = 0.785 D_1^2$
Wire mesh nozzle	50	$F_{MN} = 0.785 D_{In}^2$
Vane nozzle	400	$F_{LN} = 0.785 D_{In}^2$
Gas output	0.5	$F_{NG} = 0.785 d_{NG}^2$

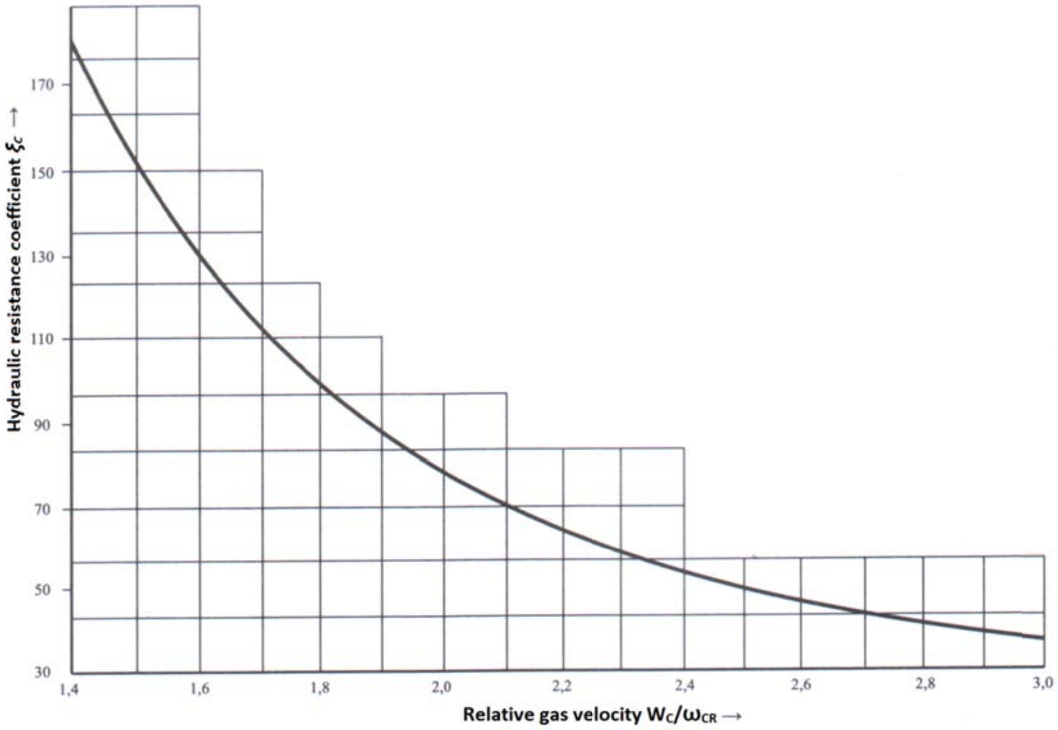


Figure 5.2 – Hydraulic resistance coefficient for the gas separator with a mesh nozzle on the relative gas velocity (relative velocity must be estimated using formula under the x-axis of above printed graph, Wc – Fig.4.7)

5.2.2. Determining the level controller height of the liquid drain pipes

Determining the level controller height of the liquid drain pipes for vertical liquid collection section and external horizontal liquid collection section (see Fig. 4.8,4.9, respectively) is carried out according to the formula:

$$h_{HL} = \frac{10^6 \cdot \eta \cdot \Delta P}{\rho_L g}, \tag{5.13}$$

where η –ripple factor, specified in the range of $\eta = 1.3–1.5$.

ΔP – resistance of the gas outlet line in the area of the liquids drain pipes, bar:

- for the wire mesh type separator is taken as equal the coagulator resistance;
- for the vane type separator is taken as equal vane nozzle resistance.

In calculating level controller height it is necessary following conditions hold:

$$h_{HL} < H - 0.1, \tag{5.14}$$

where H – distance frothed top edge of the liquid drain pipe to the upper limit of liquid level in the gas separator.

5.3. Checking calculation of the wire mesh and vane type separators

5.3.1. Checking the condition of compliance by gas capacity

The area of separator operating capacity is shown in Figure 5.1.The maximum and minimum specified capacity must be inside the shaded area.

5.3.2. Checking the condition of compliance by sizing the gas inlet and outlet pipe connections.

The value of the actual gas velocity in gas inlet and outlet pipe connections must be limited by the range of admissible velocities bounded by the curves 2 and3 in Figure 4.7. The actual gas velocity in pipe connections is determined by the formula:

$$W_{NG} = \frac{q_G}{0.785 \cdot d_{NG}^2}. \tag{5.15}$$

5.3.3. Checking the condition of compliance by liquid capacity

The liquid flow rate should be less than 0.25 m/s. The actual velocity of the liquid is determined from the condition:

$$W_{LD} = 0.382 \frac{q_L}{\sum d_{Ent}^2}. \tag{5.16}$$

5.4. The results of calculation № 5

As a result of calculations you need to obtain:

1. The conditions for **the actual gas capacity constraints**.
2. Good results of hydraulic calculation of the gas separator.
3. Good testing results.

TERM PROJECT GENERAL GUIDANCE

1. By means of lecture or text books fundamentals of natural gas processing must be studied before performing the term project
2. To choose option number of the initial data and make the necessary calculations.
3. To perform analysis of obtained results.
4. Term project executive summary should include:

a) title page, designed in accordance with Appendix 1, in which must be specified:

- the name of the object being studied;
- the group number of the student;
- full name of the student, who performed the project;
- option number of the project initial data;
- full name of the teacher, who check the project.

b) the initial data selected in accordance with option number;

c) performed calculations (graphics, monogram's, etc.)

5. Term project can be considered as completed one, if it is checked and approved by the teacher.

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3. Introduction to Oil and Gas Production. API. Book one. 1996.– 112 p.

Appendix 1

National Technical University “Kharkov Polytechnic Institute”
Department “Oil, Gas and Condensate Extraction”

Subject:
FUNDAMENTALS OF CRUDE OIL AND NATURAL GAS PROCESSING
Term project
“Sizing gathering and processing system”

Performed by student of group _______________
____
Option number of the project initial data________
Checked by _________________________________
____

Kharkiv – 201__

CONTENT

Навчальне видання

ТОПОРОВ Валерій Геннадійович
БРАТАХ Михайло Іванович
РОМАНОВА Вікторія Володимирівна

FUNDAMENTALS OF CRUDE OIL AND NATURAL GAS PROCESSING

The Term project methodical guide “Sizing gathering and processing system”

(англійською мовою)

Відповідальний за випуск *О.П. Варавіна*

В авторській редакції

Підписано до друку 04.01.2016 р. Формат 60×84 1/16 Папір офсетний.
Гарнітура Times New Roman Cyr. Віддруковано на ризографі.
Ум. друк. арк. 3,0. Обл.- вид.арк. 2,18.
Зам. 04/01/16. Тираж 100 прим. Ціна договірна

Віддруковано ФОП Крамаренко Ю.М.
Свідоцтво про держреєстрацію АБ № 815827
від 22.03.2013. р.